STATE OF VERMONT

PUBLIC SERVICE BOARD

DOCKET NO. 6860

Petitions of Vermont Electric Power Company Inc. (VELCO) and Green Mountain Power Corporation (GMP) for a certificate of public good, pursuant to 30 V.S.A. Section 248, authorizing VELCO to construct the so-called Northwest Reliability Project	)))))

PREFILED DIRECT TESTIMONY

OF

DR. JONATHAN A. LESSER

ON BEHALF OF THE

VERMONT DEPARTMENT OF PUBLIC SERVICE

December 17, 2003

Summary: Dr. Lesser's testimony addresses compliance of the proposed Northwest Reliability Project with 30 V.S.A. §§ 248(b)(2), 248(b)(4), 248(b)(6), 248(b)(7), and other related issues.

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1. INTRODUCTION

Q: Please state your name and business address.

A: My name is Jonathan A. Lesser. My business address is 112 State Street, Montpelier, VT 05620. I am currently employed as the Director, Regulated Planning, of the Vermont Department of Public Service ("DPS" or "the Department").

Q: Please describe your education and work experience

A: I hold a B.S. degree in Mathematics and Economics from the University of New Mexico, and M.A. and Ph.D. degrees in Economics from the University of Washington. At the University of Washington, I specialized in microeconomic theory, econometrics and statistics, and industrial organization. I began my career in 1983 as an Economic Analyst with Idaho Power Corporation. From 1984 to 1986, I worked at the Pacific Northwest Utilities Conference Committee, a utility and industry trade group, as an Energy Economist. From 1986 to 1993, I was an Energy Policy Specialist with the Washington State Energy Office. From 1993 to 1998, I worked at Green Mountain Power Corporation, initially as Senior

Economist and was subsequently promoted to Manager, Economic Analysis. From 1998 to 2003, I was employed by Navigant Consulting, Inc., as Senior Managing Economist, where I specialized in litigation cases involving regulated electric and natural gas utilities, investment risk analysis under uncertainty, forecasting, and energy and environmental policy. I have also taught as an Adjunct Professor of Economics in the Department of Business and Economics at Saint Martin's College in Tacoma, Washington, and in the School of Business at the University of Vermont. A copy of my resume is attached as Exhibit DPS-JAL-1.

Q: What is the purpose of your testimony?

A: My testimony has several purposes. First, I address whether, as a factual matter, the application filed by the Vermont Electric Power Company ("VELCO") to construct the so-called Northwest Reliability Project ("NRP" or "the Project") meets what I refer to as the "economic and planning" criteria set out in 30 V.S.A. § 248(b), based on my review of the economic analysis of the NRP and five alternative strategies, as performed by La Capra Associates, Inc. ("La Capra"). Second, my testimony presents the results of an independent economic analysis of the proposed NRP and various alternatives I performed using a different analytical methodology than was used by La Capra. Using the results of that independent analysis, I again determine whether the proposed NRP meets the economic criteria set out in 30 V.S.A. § 248(b).

Q: Does your testimony address whether improvements to the reliability of the electric transmission system in Vermont need to be made at all, regardless of whether such improvements would be achieved by the NRP or other alternatives?

A: No it does not. I have relied on the testimony of Mr. George Smith, P.E., a consulting electric engineer for the Department, as to whether the reliability of Vermont's transmission grid needs improvement. Moreover, I have relied on the testimony of Mr. Smith to identify those components of the NRP that are needed to improve reliability at current peak load levels, and those components needed to meet reliability requirements as peak loads increase.

If Vermont's electric transmission grid met all required reliability standards today, and would continue to do so even as peak loads increased, then the "least-cost" solution would be to do nothing. Since Mr. Smith's testimony concludes otherwise, the focus of my testimony is: "What portfolio of new investments – whether upgrades in transmission facilities, local generation, demand-side management, or combinations thereof – will be able to achieve the required level of reliability as peak loads increase at the least social cost."

Q: Please summarize your findings regarding the La Capra analysis.

A: After evaluating the La Capra economic analysis of the NRP and five alternative portfolios of resources, I have determined that La Capra's conclusions as to the cost-effectiveness of the NRP are reasonable and that, as a factual matter, the NRP meets the requirements set out in 30 V.S.A. §§ 248(b)(2), 248(b)(4), 248(b)(6), and 248(b)(7). The La Capra analysis shows that the "ARC 5" alternative developed by La Capra, which includes maximum achievable demand-side management ("DSM") acquisition, has a societal cost that is $18 million (2005$) less than the NRP, or roughly 1.5 percent lower. However, the uncertainties associated with achieving the required DSM savings, to say nothing of the uncertainty surrounding the savings estimates themselves, coupled with the difficulties of siting 120 MW of combustion turbine ("CT") generating capacity, render that option overly risky and not in the best interests of Vermonters.[1]

Q: Please summarize your findings regarding the alternative analysis you performed.

In addition to reviewing the La Capra analysis, I performed an independent analysis of the NRP and both generation and DSM alternatives. This analysis was based on a dynamic programming model developed by the Electric Power Research Institute ("EPRI"), known as the Area Investment Planning Model ("AIPM"). There are, I believe, several advantages to this approach over the

[1] The testimony of Department witness Mr. Ronald Behrns addresses the potential adverse rate impacts of the ARC 5 alternative.

deterministic approach used in the La Capra analysis. First, this approach incorporates uncertainty in future peak demand growth explicitly. Thus, it directly addresses the appropriate timing of future capacity investments. Second, this approach allows for greater investment flexibility, in terms of determining a least-cost set of capacity investments, and thus evaluates the economic criteria under 30 V.S.A. § 248(b) more accurately than does deterministic analysis of the NRP and five alternative portfolios.

The results of my independent analysis show that, even in the absence of any regional contribution as a Pool Transmission Facility ("PTF"), the expected-cost of a portfolio of investments that begins with the combined installation of a phase angle regulator and a static capacitor bank (STAT1) at the Granite Substation ("Granite PAR + STAT1"), which are components of the NRP that increase peak load capacity in Vermont, is about 30 percent lower than the next best alternative. I identified that next-best alternative as installation of 25 MW of distributed generation resources, followed by the NRP components. My analysis assumed that installation of a single generating unit, such as an individual combustion turbine, would not provide sufficient reliability in lieu of the NRP. I also performed several analyses that relaxed this assumption, however, in which case the least-expected cost decision remained installation of the Granite PAR + STAT1 first, followed by either a small 25 MW combustion turbine of the 345 kV line between West Rutland and New Haven.

For comparison purposes, I also performed an analysis assuming that, if the NRP components were removed from consideration entirely and <u>only</u> generation and DSM investments were available to meet increasing peak loads, then the optimal path would be installation of three 50MW CT's followed by additional CT's or distributed generation. However, my analysis showed that this alternative investment strategy would have more than double the expected net present value societal cost as the NRP component path.

Subsequent to installation of the Granite PAR + STAT1, my analysis shows that the subsequent least-expected-cost incremental investment (after installation of the Granite PAR + STAT1, to be the 345kV line from West Rutland to New Haven, which is also a component of the NRP. Subsequent to that investment, my analysis shows a second dynamic reactive power source, (or STATCOM) ("STAT2") is least-cost.

My analysis also shows that the Granite PAR + STAT1 is the initial least-expected cost investment even assuming higher costs for the 345 kV line and the second STATCOM device at the Granite substation, as discussed in the testimony of DPS witness Mr. George Smith. Even with these higher costs, there is still a 95 probability that the Granite PAR +STAT1 would be followed by the 345 kV line and then a second static capacitor bank at the Granite substation. The only difference between the analysis using the original VELCO costs and the higher costs developed by Mr. Smith is the five percent probability that, if peak loads were to grow very slowly, the Granite PAR + STAT1 could be eventually followed by a combustion turbine.

I also evaluated the cost-effectiveness of the NRP assuming a lower "societal" discount rate and assuming higher system avoided energy costs. Although both of those factors tend to favor generation and DSM alternatives relative to the NRP, my analysis shows that installation of the Granite PAR + STAT1 continues to be the least-expected cost alternative, with the same 95 percent probability that it would be followed by the 345 kV line and the second STATCOM device at the Granite substation. Finally, I evaluated the NRP assuming a lower overall probability distribution of future peak load growth. Again, the results showed that the least-expected cost alternative would be installation of the Granite PAR + STAT1, followed by the 345 kV line, and the second STATCOM device at the Granite substation.

As a result of my analysis, I believe that the components of the NRP that increase peak load capacity in Northwest Vermont clearly meet the economic and planning criteria under 30 V.S.A. §248. My analysis also shows that it is unlikely for DSM investments to be part of a least-expected cost portfolio to meet future peak demand, as the installation costs are higher, and anticipated savings lower, than either the NRP or local generation alternatives. Moreover, my conclusions about

DSM do not consider uncertainty surrounding projected DSM savings, nor the ability to achieve projected savings in a timely fashion, nor the potential rate increases that would be borne by Vermonters if a "Maximum DSM" strategy, as described under La Capra's "ARP 5" resource scenario, were followed.

Q: Did your analysis compare the entire cost of the NRP with the entire cost of alternative investments that could meet anticipated increases in peak loads?

A: No. The reason for this is as follows. The testimony of Department witness Mr. George Smith shows that a number of component investments included in the NRP project are needed today, regardless of forecasts of increasing peak loads in Northwest Vermont. These components, such as the Blissville PAR, Essex Line Breaker, etc., do not increase peak load capacity in the region. Rather, according to Mr. Smith, they increase reliability at existing peak loads, and must be installed.

As such, the appropriate economic comparison is to compare the costs and benefits of those components of the NRP that can increase peak load capacity with other similar alternatives, such as local generation or DSM. In essence, this approach assumes that alternative investments like local generation are not substitutes for those components of the NRP that are needed today for reliability purposes.

Q: Did your analysis consider PTF treatment for the NRP components, which would mean that Vermont ratepayers' would only be required to pay a small percentage of the total actual costs of the NRP?

A: No. I did not incorporate PTF savings in my economic analysis. Had I done so, the differential between the least-cost NRP component investment path, and an alternative path, would have been much larger.

2. RELEVANT ECONOMIC AND PLANNING CRITERIA OF 30 V.S.A. § 248

Q: Please discuss the relevant economic and planning criteria under 30 V.S.A. § 248 that your testimony addresses.

A: My testimony primarily addresses the subsections 248(b)(2), 248(b)(4), 248(b)(6), and 248(b)(7).

Q: Please discuss the cost-effectiveness provisions of 30 V.S.A. § 248(b)(2) as it relates to the proposed NRP.

A: The language of 30 VSA § 248(b)(2) states that a proposed investment

> [I]s required to meet the need for present and future demand for service which could not otherwise be provided in a more cost effective manner through energy conservation programs and measures and energy-efficiency and load managements measures, including but not limited to those developed pursuant to the provisions of sections 209(d), 218c, and 218(b) of this title.

30 V.S.A. § 248(b)(2)'s citation to 30 V.S.A. § 209(d), 218c, and 218(b) requires testing the NRP against non-transmission measures, such as energy efficiency programs, which meet the requirements of those sections. Since § 248(b)(2) uses the phrase, "including but not limited to," it also means that the NRP must be tested against such non-transmission measures generally.

Q: Please discuss the cost-effectiveness provisions of 30 V.S.A. § 248(b)(4) as it relates to the proposed NRP.

A: 30 V.S.A. § 248(b)(4) states that a proposed investment "[W]ill result in an economic benefit to the state and its residents." This criterion requires an evaluation of the likely benefits and costs to the state and its residents of the NRP and any proposed alternatives.

Q: Would an assessment of the impacts of the NRP on retail electric rates also be a factor in determining compliance with 30 V.S.A. § 248(b)(4)?

A: Yes. Higher electric rates can impose adverse economic impact on the state businesses and residents. Department witness Mr. Ronald Behrns discusses the rate impacts of the proposed NRP and alternatives in his testimony. The scope of my testimony is limited to evaluating the provisions of 30 V.S.A. § 248(b).

Q: Please discuss the cost-effectiveness provisions of 30 V.S.A. § 248(b)(6) as it relates to the proposed NRP.

A: 30 V.S.A. § 248(b)(6) states that:

> [W]ith respect to purchases, investments, or construction by a company, is consistent with the principles of resource selection expressed in that company's approved least cost integrated plan.

VELCO does not have an approved least-cost integrated plan, as the Board has not required VELCO to submit one. In Docket No. 5737, the Board determined that, with respect to a company that does not have an approved least-cost integrated plan, compliance with § 248(b)(6) requires a determination of whether the proposed project complies with least-cost planning principles. Docket No. 5737, Order, April 17, 1995, at 16-17.

Q: Please discuss the cost-effectiveness provisions of 30 V.S.A. § 248(b)(7) as it relates to the proposed NRP.

A: 30 V.S.A. § 248(b)(7) states that:

> [E]xcept as to a natural gas facility that is not part of or incidental to an electric generating facility, is in compliance with the electric energy plan approved by the department under section 202 of this title, or that there exists good cause to permit the proposed action.

This requirement means that any new capacity additions identified to meet reliability concerns must be consistent with the currently approved Twenty Year Electric Plan ("Plan"). Although the Department issued its Final Draft of the 2004 Energy and Electric Plan on December 4, 2003, consistency is determined based on the most recent Plan, which was issued in 1994. However, because the

1994 Plan is clearly out of date, there is good cause to permit the proposed action whether or not it complies with the 1994 Plan. Therefore, I recommend that consistency be measured based on the Final Draft 2004 Twenty-Year Energy and Electric Plan.

3. EVALUATION OF LA CAPRA ANALYSIS

Q: Please summarize the La Capra analysis.

A: The La Capra analysis presents a fairly standard engineering-economic analysis of the NRP. The analysis determined that reliability levels in Northwest Vermont need improvement, based on standard reliability criteria used by NEPOOL. (Again, the testimony of Department witness Mr. George Smith discusses the need to improve reliability levels in more detail.)

La Capra compared the present value cost of the NRP against the present value cost of five alternative approaches that were designed to provide equivalent reliability levels as the NRP. These approaches included various combinations of local generation alternatives, as well as one approach that incorporates generation plus aggressive DSM investment. La Capra used typical engineering cost estimates for generation alternatives, and relied on a report prepared by Optimal Energy for DSM investment cost and capacity. La Capra evaluated these alternatives based on their annual "economic carrying costs," as well as operation, maintenance, and fuel costs. Moreover, La Capra also relied on a forecast of future wholesale electric prices to determine the net savings from reduced purchases of electricity. La Capra also performed several sensitivity studies to determine the "robustness" of the NRP under different conditions, including high oil and natural gas prices, high and low Vermont load growth, and transmission improvements that make generation in Southeast Massachusetts and Rhode Island accessible to Vermont.

Q: Is the La Capra economic analysis adequate and reasonable?

A: The La Capra analysis is reasonable to the extent that the assumptions used to form the basis of the economic analysis all appear to be reasonable. Moreover, the structure of the La Capra analysis is reasonable, as it addresses both the direct monetary and total societal costs of the NRP, and evaluates a reasonable number of alternatives that cover a wide range of options.

I do not believe, however, that the La Capra analysis is adequate for several reasons. First, the La Capra analysis is fundamentally deterministic. Although the analysis presents several sensitivity studies on load growth and fuel prices, the study did not examine uncertainty, especially load growth uncertainty, in an economically rigorous and dynamic way. Based on my experience with so-called "distributed utility planning" exercises, load growth uncertainty is the most critical determinant of "least-cost" capacity investments. And, it is for this reason that I evaluated the NRP and various alternative capacity investments (including DSM) using the dynamic programming approach of the AIPM.

Second, the "economic carrying charge" ("ECC") model is what I term an "accounting" framework.[2] By this I mean that the ECC model calculates annual cash flows that include taxes, equity returns, and depreciation. Although these are clearly costs that affect the calculation of rates customers might face, I believe that a "pure" economic approach is more appropriate and accurate, especially for a "societal" investment analysis. In this way, it is easier to separate economic from accounting costs.

Third, the La Capra analysis compares alternatives that do not appear to be strictly equivalent on an economic basis. For example, ARCs 1 – 4 add increasing amounts of generating capacity, from 225 MW to 350 MW, respectively. Although the generation investments in each of these ARCs may result in the same expected level of reliability based on load carrying capability, the differences in timing of these investments may raise "apples vs. oranges" concerns about the direct comparability of the alternatives.

Q: Please define a "pure economic approach."

[2] A complete description of the ECC model used by La Capra is contained in VELCO Exhibit MDM-2, Appendix 9.

A: By "pure economic approach," I mean an approach that is based on "real" cash flows, rather than accounting flows or transfer payments. Depreciation, for example, is an accounting concept, not an economic one. While depreciation affects tax liability and net accounting cash flows, it does not affect the economic cost of an investment. The overnight cost to construct a generating unit, for example, does not depend on how fast the generating unit is depreciated over time. Similarly, tax considerations should not be calculated on an individual unit basis, as this distorts overall costs. Firms incur a tax liability based on their overall revenues and costs, not on the revenues and costs of any single asset. Moreover, taxes are simply transfer payments. Although tax policies can obviously affect a firm's investment decisions, from a societal standpoint taxes do not matter.

In the case of the NRP and alternatives, the pure economic approach develops an analysis based on the direct (and indirect societal) costs. Thus, if the NRP has an overnight capital cost of $128 million in 2005$ in the year 2005, then that is the cost that is recorded. It makes no difference how that capital cost is amortized over time, because the present value of any amortization must equal the overnight capital cost. Similarly, ongoing fuel, operations, and maintenance expenses associated with generating resources are measured as cash outlays at the time of occurrence. Taxes, capital structure, and depreciation are ignored, because they can distort the economic analysis.

4. ALTERNATIVE ECONOMIC ANALYSIS

Q: Please summarize your alternative economic analysis.

A: My alternative economic analysis used the EPRI AIPM model, which was designed to evaluate distributed utility ("DU") planning alternatives using a dynamic programming approach. A description of this approach and the underlying methodology is contained in the article, "Capacity Planning Under Uncertainty: Developing Local Area Strategies for Integrating Distributed Resources," which was published in The Energy Journal, and is attached as Exhibit DPS-JAL-2.

In essence, my alternative analysis answers the following question: "What is the set of capacity investments over time that results in the least-expected cost, given uncertainty over future peak load growth?" The result of my analysis produces the following:

- The least-expected-cost investment that should be pursued first; and
- A series of contingent investments that should be performed subsequently, based on realized outcomes of load growth uncertainty.

Using the AIPM, I am also able to rank the relative expected economic costs of installing different alternatives first. Moreover, I can determine the least-expected-cost combination of capacity investments, rather than having to pre-select specific portfolios manually.

4.1. Description of the AIPM

Q: Please describe how the AIPM Model works.

A: Fundamentally, the AIPM compares the value of flexibility associated with installing smaller capacity investments (akin to a “just-in-time” production approach) with the value of scale economies achieved by installing larger capacity increments. If there were no economies of scale, the investment problem would be much simpler: always install smaller, cheaper capacity investments. However, that is generally not the case: small increments of generation or DSM tend to have higher costs on a per-kW basis than do large investments such as transmission lines, substations, and new distribution circuits. The analytical question, therefore, is how best to value flexibility when future capacity growth is uncertain. This is the analysis the AIPM performs.

The following example can clarify this approach. Suppose load growth will be 10 MW this year with certainty. Next year, however, there is a 60 percent chance that loads will grow an additional 90 MW if an industrial customer expands its manufacturing facilities. If the industrial customer does not expand, there will be no increase in load growth. In either case, assume there is no more subsequent load growth in any future years. The planner must decide between two capacity investment alternatives today: a traditional system upgrade with a capacity of 100 MW and capital cost of $100 million, or a 10 MW distributed generation technology with a capital cost of $20 million (twice the cost per kW of the large system upgrade).

There are two alternative investment paths: install the large upgrade today, meeting all future load growth, or install the small distributed generation technology and "wait-and-see" if the new load appears. In a traditional deterministic analysis, the planner would either base the investment on the most likely increase in load growth (100 MW) or the expected increase (64 MW = 10 + (0.6)*90 MW). In both cases, the large investment must be installed to meet expected or most likely future load growth. If a dollar today is worth ($0.90) next year (implying a discount rate of 11.1%), then the present value cost of installing the large investment today is $100 million, while the present value of installing the small investment today and the large investment next year is $20 Million + $100 Million * (0.90) = $110 million. Therefore, using the deterministic approach, the least cost solution is to install the large investment today.

We can compare these costs with the wait-and-see approach, which has the planner install the small investment today and then install the large investment only if the new load growth actually appears. The present value cost of this approach is $20 Million + (0.9)* [(0.60)*$100 Million] = $74 million. Thus, the distributed generation combined with a "wait-and-see" approach reduces the expected present value cost by $26 million. The value of the distributed generation is a result of the flexibility it provides, not its per-unit cost.

The AIPM directly incorporates this value of flexibility by addressing an important question in transmission and distribution planning: at what point in the future will load growth result in the need for new capacity investments? To answer that question, load growth uncertainty must be addressed. The AIPM does this using a Markov-chain model. Such a model is simple to implement, yet robust in that it can capture the complexities of future load growth uncertainty. In essence, a Markov-chain model assumes that loads vary by moving between different states, such as between "Low-growth trend" and "High-growth trend" states, and that the time spent (duration) in individual states is also uncertain. In the example problem, loads could be described as moving from a "Medium-growth" state of 10 MW increases to either a "High-growth" state, in which the new industrial load materializes, or a "Low-growth" state, in which there are no further load increases.

The AIPM evaluates potential capacity investments today and then, given each, evaluates the "time to the next decision." For example, if the 100 MW investment were installed today and loads continued to grow at 10 MW per year, the time to the next decision would be 10 years. At that time, the model would evaluate the feasible investment alternatives, and future load growth, and move on the next needed decision, and so forth. The actual solution to determining the least-expected-cost set of investments is accomplished by using a dynamic programming algorithm.

Q: Please explain the term "dynamic programming."

A: Dynamic programming is an approach developed to solve sequential, or multi-stage, decision problems; hence, the name "dynamic" programming. Basically, what dynamic programming approach does is that it solves a multi-variable problem by solving a series of single variable problems. The optimal sequence of solutions is calculated recursively, beginning at the end of the planning horizon and moving backwards to the beginning of the horizon. The essence of dynamic programming is Bellman's <u>Principle of Optimality</u>. This principle, states that:

> *An optimal policy has the property that whatever the initial state and the initial decisions are, the remaining decisions must constitute an optimal policy with regard to the state resulting from the first decision.*

Rutherford Aris restated the principle in more colloquial terms:

> *If you don't do the best with what you have happened to have got, you will never do the best with what you should have had.*

In the case of decision trees, for example, dynamic programming requires "rolling back" the tree to reach the root solution, thus identifying the best solutions at each decision stage. The result is an analysis that provides the least-expected cost investment path, beginning with an investment today and then a series of contingent investments in the future. (Of course, contingent investments need not be committed to initially, and thus subsequent analysis can be performed.)

Q: Does the AIPM constrain the analysis to meeting projected loads in the year 2011?

A: No. As I will discuss in more detail in Section 4.2, uncertainty about future load growth is fundamental to the AIPM. For this analysis, I evaluated load growth over a 15-year time horizon. I believe this is a reasonable compromise between model tractability (the longer the explicit time horizon, the more computationally intensive the analysis), and the influence of so-called "end-effects."[3] End-effects refer to a general problem of addressing the costs and benefits of long-lived assets, such as by estimating salvage values. This is necessary so as to ensure that alternatives with different lifetimes (*e.g.*, 40-year lives for transmission plant, 25-year lives for combustion turbines, etc.) are compared on an equal basis.

Q: Please discuss how the AIPM incorporates the avoided generation costs associated with both generation and DSM investments.

A: The AIPM credits avoided system energy costs, including externalities, based on the amount of generation displaced when the specific generating unit is used to meet capacity needs. For example, suppose a 100 MW generating unit has a

[3] The AIPM treats end-effects in one of two ways: Either by calculating net salvage values at the end of the study horizon, or by calculating the "cost-to-go," which replaces the specific resources selected at the end of their useful economic lives with a generic transmission resource. I used the former method, which is a standard approach in economic analysis to address end effects.

marginal energy cost of $80/MWh, based on the delivered cost of natural gas, the unit's heat rate, and its variable O&M costs. Suppose further that cost of system energy is $50/MWh when the local capacity is needed, and that the unit is needed for 100 hours. The AIPM includes the incremental costs of running the unit for those 100 hours at a cost of $80/MWh. The total incremental cost is therefore 100 hours * $80/MWh * 100MW = $800,000. The plant avoids 10,000 MWh of system energy, which has a value of 10,000MWh * $50/MWh = $500,000. Therefore, the net cost of running the plant is the difference in the two cash flows, or $300,000.

Q: What if the incremental cost of generation from a local generating unit is lower than the price of system energy?

A: In that case, the AIPM would make the same incremental cost calculation, only the incremental cost would be below zero. The AIPM would credit the generating plant with avoided generation as long as the plant's generating capacity was needed to meet local area peak loads. The model does not "dispatch" local generation to meet general system energy requirements beyond what is needed for peak loads.

Q: How does the AIPM treat energy savings realized through DSM investments?

A: Avoided system energy costs are treated by the AIPM in the same way as for local generation alternatives. The difference is that the variable production costs of DSM are assumed to be zero.

4.2. Modeling Assumptions

Q: Please discuss the modeling assumptions you used to prepare your alternative analysis.

A: I relied primarily on the La Capra analysis for the data and assumptions I used in the AIPM. I did update some of the data, such as higher natural gas prices for the CT and combined-cycle "CC" generation options, to reflect more current market conditions. I also developed assumptions regarding load growth uncertainty, based on the load growth assumptions of the La Capra model and my review of historic peak load growth in Vermont.

Q: Did you assume that the entire NRP could be avoided?

A: No. My analysis focused on those components of the NRP that would increase peak capacity in Northwest Vermont. I did not evaluate components of the NRP that are designed to improve reliability at existing load levels.

Therefore, my analysis evaluated generation and DSM alternatives that would increase peak capacity in Northwest Vermont against those components of the NRP that would increase capacity. Based on the testimony of Mr. George Smith, the initial components necessary to increase peak capacity would be installation of the Granite Substation PAR and STAT1, which would provide 95 MW of additional capacity. This would be followed by the 345kV line from West Rutland to New Haven, which would provide an additional 40 MW of capacity, and then by a second static capacitor bank (STAT2) at the Granite substation, which would provide a further 60 MW increment of new capacity. This ordering of investments was based on Mr. Smith's review of the interface power flows under alternative transfer conditions.

Q: Please discuss the component costs of these three NRP investments that would increase peak capacity in Northwest Vermont.

A: VELCO indicated that the entire Granite substation cost would be $34.7 million. Of that total, the cost of the PAR (plus yard expansion) and the first static capacitor bank (STAT1) totals $27.1 million. VELCO estimated the cost of the second capacitor bank (STAT2) to be $7.6 million. The cost of the 345 kV line from West Rutland to New Haven, plus associated substation work, was estimated by VELCO to have a cost of $25.24 million. Finally, VELCO estimated the cost of installing the second STATCOM device to be $7.6 million. I used these VELCO cost assumptions in my initial analysis.

I also performed sensitivity studies, increasing the costs of the 345 kV line and the STAT2 alternatives consistent with Mr. Smith's testimony regarding his expectation of higher costs for those components of the NRP. Mr. Smith estimated that the cost of the 345 kV line itself would be $7.5 million higher (roughly $600,000 per mile versus VELCO's $389,000 per mile estimate). Moreover, Mr. Smith estimated that the cost to install the second STATCOM device at the Granite substation would have a total cost of $13 million. The reasons for these cost increases are explained in Mr. Smith's testimony.

4.2.1. Generation and DSM Resource Alternatives and Capital Costs

Q: Please discuss the generation and DSM resource alternatives you evaluated and their capital costs.

A: In addition to the NRP components discussed previously, I incorporated the 25 MW CT, 50 MW CT, 25 MW distributed generation ("DG"), 100 MW CC, 150 MW CC, and 200 MW CC alternatives. I also included transmission investments that could be installed only after the three NRP components had been previously installed. These "post-NRP" transmission investments are discussed in the testimony of DPS witness Mr. Smith. Finally, I also included the DSM resource identified in ARC 5. However, unlike the La Capra analysis, I separated the DSM resource into five distinct supply blocks, which could be installed in sequence. Doing so increases the inherent flexibility value of DSM resource by not forcing DSM to be committed to on an "all or nothing" basis.

I based the overnight capital costs of the generating resource alternatives on the La Capra data published in Appendix 7 of its report. The table below summarizes those overnight capital costs:

Generation Alternatives and Overnight Capital Costs

Generation Resource	Capital + Installation Cost (2005$/kW)
25 MW CT	$640
50 MW CT	$585
100 MW CC	$882
150 MW CC	$720
200 MW CC	$692
25 MW DG	$1,067

Source: Exhibit VELCO-MDM-2, Appendix 7.

After discussion with DPS witness Mr. George Smith, I assumed that, for the purposes of ensuring adequate reliability, three 50 MW CT's ("3x50MW CT") would have to be constructed in lieu of any of the components of the NRP that would increase peak capacity. In other words, I assumed that, a 3x50MW CT option was an alternative to the NRP, but that construction of only one or two 50 MW CT's would not provide sufficient reliability to meet existing ISO-NE standards. This is the same assumption used in the La Capra analysis for all of the ARC cases. I also performed sensitivity studies where I relaxed this assumption, allowing individual generating units to be installed without first installing NRP some NRP components.

Subsequent to the installation of the 3x50MW CT option, I assumed that individual generating units could be installed over time to meet future load growth. The table below shows the initial resource alternatives I assumed.

Initial Resource Alternatives	Secondary Resource Alternatives
Granite PAR + STAT1	Granite PAR + STAT1
3x50MW CTs	345kV
25 MW DG	25 MW CT
DSM - Phase 1	50 MW CT
	100 MW CC
	150 MW CC
	200 MW CC
	25 MW DG
	DSM - Phase 1
	DSM - Phase 2

Thus, I assumed there were four initial capacity investment alternatives. Subsequently, there could be up to eight alternatives, depending on which capacity investment was selected initially. For example, if the 3x50MW CT investment were initially selected, it could be followed by the Granite PAR + STAT1, installation of single generation units, or DSM. If DSM - Phase 1 were initially selected, it could be followed by individual generation units, the second phase of DSM, the Granite PAR + STAT1, and so forth.

Q: Please explain how you modeled the added capacity from the different generation options.

A: I derated the installed capacity values for the generating options to reflect their summer ratings, as was done in the La Capra study. This involved derating the combustion turbine alternatives by 20 percent, and the combined-cycle alternatives by 15 percent.

Q: Did you address the thermal load carrying capabilities of generating options?

A: No. For the purposes of my analysis, I assumed that generation alternatives would not be limited by their LCC values, but only limited to the extent of their summer deratings.[4] The reason is that it is not possible to calculate the LCC values without performing load flow analyses on each potential combination. Thus, I used a conservative assumption that tends to favor generation, since LCC values will be less than or equal to the summer rated capacities of generating units.

Q: Did you incorporate congestion costs into your AIPM analysis?

A: No. The AIPM was not designed to incorporate congestion costs that can arise under a locational marginal pricing system, since its main purpose is evaluation of local area distribution options. All other things equal, therefore, the AIPM would tend to overvalue local generation alternatives slightly, since generation alternatives do not eliminate congestion charges.

Although generating resource options do not eliminate congestion charges, they can provide a "hedge" against congestion by limiting congestion charges to the marginal cost of production. For example, suppose that, in the absence of any

[4] For example, the La Capra analysis assumed that a 50 MW nameplate CT would have a summer capacity of only 40 MW, which is a 20 percent derating.

new generation, the uncongested New England spot market price on a summer peak day is $70/MWh and the price in the Vermont zone is $100/MWh because of congestion. If generating resources were introduced having incremental production costs of $80/MWh, then the price in the Vermont zone would decrease to that $80/MWh value, thus reducing congestion costs by $20/MWh. Hence, the presence of generating resources reduces congestion costs and effectively introduces a financial hedge, with a strike price equal to the generating units' incremental production costs. Of course, adding transmission capacity also hedges congestion costs and, if that new transmission capacity is sufficient, will eliminate congestion costs entirely.

Q: Please discuss the DSM alternatives, specifically the DSM "Phases" you modeled.

A: Rather than analyze the more restrictive La Capra analysis of maximum comprehensive DSM as an entire package, I assumed that DSM could be developed in "phases" over time. In this way, I could evaluate the cost-effectiveness of DSM increments, rather than simply evaluating an "all-or-nothing" DSM strategy. I used this approach because I believe it to be more indicative of DSM programs in reality, which can be started and stopped, depending on resource needs.

Q: Please discuss the operations and maintenance costs assumptions you relied on for your analysis.

A: I used the operation and maintenance ("O&M") cost assumptions as published in VELCO Exhibit MDM-2,Appendix 7 of the La Capra analysis.

4.2.2. Load Growth Assumptions

Q: Was the La Capra analysis was based on a peak load forecast prepared by the DPS in the summer of 2002?

A: Yes.

Q: Did the DPS prepare a new energy forecast as part of its recently released Final Draft 2004 Twenty Year Energy and Electric Plan?

A: Yes. The DPS prepared long-term econometric forecasts of energy growth for residential, commercial, and industrial customers.

Q: Did the DPS prepare a new peak load forecast as part of the Final Draft 2004 Twenty Year Energy and Electric Plan?

A: No. The DPS did not feel it was necessary, since a Vermont peak load forecast had been prepared last year. Moreover, the Plan was more focused on long-term energy growth, rather than peak load increases, since it is energy growth that is typically the focus of utilities' resource planning efforts. This is not to deny the importance of peak loads in utility planning efforts. The DPS is an active participant in the Area Specific Collaboratives ("ASCs") that were created as part of the Memorandum of Understanding approved in Docket No. 6290.

Q: Please discuss the assumptions you used to model load growth uncertainty.

A: As I discussed previously in my testimony, the EPRI AIPM relies on a "Markov-chain" model to evaluate uncertainty about future load growth. The AIPM allows users to specify the Markov-chain in one of two ways. The user can directly input the Markov-chain coefficients into the model (*e.g.*, the probability of jumping from load growth state A to load growth state B, etc.), and the specific load growth states themselves (*e.g.*, State A = 3 percent annual growth in capacity; State B = 5 percent annual load growth, etc.). Alternatively, users can use a component of the EPRI AIPM called the "Load Assessor."

The Load Assessor allows the user to construct up to five separate load growth scenarios (e.g., "Low," "Base," High," etc.), and growth rate assumptions for those scenarios, including the "persistence" of scenarios (*i.e.*, what is the average duration in a given load growth scenario). Moreover, the scenarios themselves are stochastic. That is, load growth in any given scenario can vary. Thus, overall load growth over time will depend on the specific load growth "state-of-the-world," that characterizes growth at a given time, as well as the specific growth within that given state. Finally, load growth over time will depend on the relationship of the load growth states to one another, and the likelihood of switching from a given state to another. This combination of uncertainties is used by the EPRI Load Assessor to calculate the Markov-chain matrix values automatically for the AIPM. The appealing aspect of the Load Assessor is that it quickly creates a chart showing the mean capacity level, and absolute (99.99 percent) upper and lower bounds.

I constructed load scenarios so that the mean load growth would mimic the forecast peak load growth assumed by La Capra. Based on historical peak load growth data, I estimated that peak loads in Vermont have been growing at a two percent rate annually. I used this growth rate as my initial load growth state. To determine an overall probability distribution of load growth, I examined historic peak load growth rates and determined maximum and minimum levels of growth.[5] I created three specific scenarios: Low, Base, and High. The specific data for each scenario used to create the Markov transition matrix are shown in the following table:

DPS "Summer 2002 Forecast" Load Growth Scenario Parameters

Scenario Name	Avg. Growth Rate (%)	Lowest Growth Rate (%)	Highest Growth Rate (%)	Estimated Probability
Low Growth	1.0%	0.0%	2.0%	0.30
Base Growth	2.2%	1.5%	4.0%	0.55
High Growth	3.5%	2.5%	8.0%	0.15

[5] The AIPM assumes a minimum growth level of 0.0 percent. The reason is that areas in which peak loads are declining clearly do not need to make new T&D investments related to load growth.

I assumed that the "Low" peak load growth scenario would be characterized by average growth of one percent per year, with a range of between 0 percent and 2 percent. The "Base" peak load growth scenario was characterized by average growth of 2.2 percent per year, with an overall range of 1.5 percent to 4.0 percent. Finally, the "High" growth scenario assumed an average of 3.5 percent per year growth, and a range of between 2.5 percent and 8.0 percent. The resulting Markov-chain probability matrix parameters are shown in Exhibit DPS-JAL-3.

Q: Did these scenarios accurately reflect the peak load forecast developed by the DPS in the summer of 2002?

A: Yes. As shown in Exhibit DPS-JAL-4, the mean load growth resulted in a forecast peak load of about 1200 MW in 2012, as was projected by the DPS forecast. Exhibit DPS-JAL-4 also shows the overall probability distribution of load growth I developed, including the upper and lower bounds.

Q: What other steps did you take to address uncertainty about peak load growth?

A: To further address uncertainty about peak load growth, I created a lower overall probability distribution of future load growth. I did this by reducing the average growth in each of my three growth scenarios, and reducing the maximum growth that could occur in any given scenario. I also reduced the probability of a "high" growth scenario from 15 percent (0.15) originally, to just 10 percent (0.10).

DPS "Lower Overall Growth" Scenario Parameters

Scenario Name	Avg. Growth Rate (%)	Lowest Growth Rate (%)	Highest Growth Rate (%)	Estimated Probability
Low Growth	0.5%	0.0%	1.5%	0.30
Base Growth	1.25%	1.0%	2.5%	0.60
High Growth	2.5%	2.0%	6.0%	0.10

The resulting Markov chain model transition probabilities are shown in Exhibit DPS-JAL-3. The overall lower load growth probability distribution is also shown in Exhibit DPS-JAL-4. The effect of lower load growth is to favor more flexible solutions, such as DSM and local generation, because lower load growth allows those solutions to defer the need for "traditional" T&D upgrades longer.

Exhibit DPS-JAL-4 shows peak loads increasing from their year 2003 value of 1005 MW to about 1200 MW in the year 2012. The average peak load is expected to increase to about 1350 MW after 15 years, or by the year 2018. The lower and upper probability bounds of load growth are shown to be 1115 MW and 1910 MW, respectively. In the Low case, which is also shown in Exhibit DPS-JAL-4, the peak load is expected to be about 1125 MW in the year 2012, and reaching only 1200 MW in the year 2018. The lower and upper probability bounds in the year 2018 for this scenario are 1053 MW and 1464 MW, respectively.

Q: Please explain why this approach to modeling load growth uncertainty is more appropriate than construction of deterministic load growth "scenarios."

A: Relying solely on deterministic load growth scenarios for sensitivity studies fails to incorporate the dynamism of peak load growth in several ways. First, it is unlikely that peak load growth will continuously follow any one given "scenario." Rather, load growth is much more likely to vary as the underlying economic drivers change, and those drivers are often cyclic. Moreover, none of the least-cost alternatives identified under any specific scenario may be the least <u>expected</u> cost. Therefore, in my opinion, it is more appropriate to identify alternatives that are least-cost in a probabilistic sense, rather than a deterministic sense.

<u>4.2.3. Discount Rate Assumptions</u>

Q: Please discuss the discount rate you used for the analysis.

A: I used two different discount rates. First, I used the 10 percent discount rate assumed by La Capra, which reflected an overall weighted average cost of capital ("WACC") for the project, based on La Capra's financing assumptions. Given La Capra's forecast of 2.5 percent inflation per year for the study horizon, a 10 percent nominal discount rate translates into a real (inflation-adjusted) discount rate of 7.2 percent.[6]

[6] To determine the real discount rate, one solves the following equation for r:
$(1 + r) = (1 + N) / (1 + i)$, where r = the real discount rate, i = the inflation rate, and n = the nominal discount rate.

I also performed an analysis using a "societal" discount rate in order to review the NRP under a "societal" analysis. Such an analysis evaluates whether the investment in question would have the lowest societal cost, where societal costs are generally inferred as including non-monetary costs, such as environmental costs. If one uses such an analysis, one should adopt a societal discount rate, rather than a private discount rate. The standard discount rate used by economists for this purpose is called the social rate of time preference ("SRTP"). The SRTP represents society's time preference.[7] Although it cannot be observed directly, the SRTP is generally thought to equal the average real (inflation-adjusted) interest rate on long-term government securities, and has been estimated to be between 2 and 4 percent. For the purposes of my analysis, I used a real discount rate of 3 percent as the SRTP.

4.2.4. Generation Fuel Price Assumptions

Q: Please discuss the fuel price assumptions you used for the local generation alternatives.

A: I assumed a delivered (to Vermont) price of natural gas equal to $4.25 per MMBtu, which includes a $0.75/MMBtu transportation charge. I also assumed the price of natural gas would escalate at the rate of inflation.

[7] For a more detailed discussion, see J. Lesser, et al., Environmental Economics and Policy, Addison Wesley Longman, 1997, Chapter 13.

4.2.5. Electric Price Assumptions

Q: Please discuss the electric price assumptions you used for the local generation and DSM alternatives.

A: Local generation and DSM provide benefits in that they avoid the need to make system energy purchases. For the purposes of my analysis, I assumed a price of $45/MWh in the summer, escalating at the rate of inflation. This is consistent with the DPS 2003 electric price forecast. I also performed a sensitivity study, assuming higher summer prices of $60/MWh, which would favor development of the local generation and DSM alternatives.

4.2.6. Environmental Externalities Assumptions

Q: Please discuss the environmental cost assumptions you relied on for your analysis.

A: I used the environmental cost assumptions as shown in Appendix 11 of the La Capra analysis [Exhibit VELCO-MDM-2, Appendix 11]. It is my understanding that these values were based on and extrapolated from the settlement externalities values agreed on in the approved Memorandum of Understanding in Docket No. 5980 for use in system-wide DSM programs [Exhibit VELCO-MDM-2, at 66, n.17.]

4.3. Results of AIPM Analysis

Q: Please summarize the results of your analysis.

A: The results of my analysis indicate that an investment path that incorporates the three components of the NRP that increase peak load capacity (Granite PAR + STAT1, 345 kV, STAT2) is the least-societal cost alternative, and has a 30 percent lower expected present value societal cost (using the VELCO discount rate) than the next best alternative, which is an investment path beginning with installation of 25 MW of distributed generation (DG). The optimal investment path is shown in Exhibit DPS-JAL-5, which is an output file produced by the AIPM.

Q: Please describe the investment path shown in Exhibit DPS-JAL-5.

A: The exhibit shows "Decision Stage" nodes and "Chance" nodes. The initial decision is shown in the Column (1), and is labeled "Decision (Stage 1)." It shows the initial planning horizon time, t = 0.00, an initial peak load of L = 100500, and an initial cost of $65,030.10.[8] (The load shown is reported in kWx10, since the AIPM was designed to address local areas with distribution loads below 1,000 MW. This makes no difference to the analysis, since we merely scale the capacity increments down by 10, and scale the variable cost components up by 10, to ensure consistency.)

[8] This cost figure is in thousands of dollars.

This first decision node shows GR1, which is the Granite PAR + STAT1. Following that, there is a "Chance" node in Column (2). There are three chances, reflecting a three-branch representation of the peak load probability distribution shown in Exhibit DPS-JAL-4. Associated with each chance node, there is a probability of occurrence, p, a time value, and a peak load growth rate for that branch. For example, the low growth branch has a probability of p = 0.0481 and peak load growth along that branch equal to 0.79 percent (g = 1.0079). The time value shown, t = 11.48, reflects the number of years until the additional 95 MW of capacity provided by GR1 would be "used up." In other words, at a growth of 0.79 percent annually, peak loads would increase by exactly 95 MW over 11.48 years.[9] This is why the AIPM structure is based on "time to the next decision." Rather than attempting to determine what investments must be made in fixed time increments, the AIPM simplifies the dynamic programming problem (*i.e.*, reduces the number of "branches" from the decision "tree"), by only creating branches when decisions must be made.

Continuing to follow this one path, after 11.48 years, the model selects the 345kV line, as shown in Column (3). Since that line adds 40 MW of capacity, the model again approximates the probability of load growth using a three-branch representation, as shown in Column (4). Thus, the model determines the next low growth branch as having a probability of p = 0.1626, with a growth rate of 0.6

[9] (1005 MW)$(1.0079)^{11.48}$ = 1100 MW

percent (g = 1.0061). At that growth rate, it would take 5.89 years (t = 5.89) to exhaust the new capacity. Since that would take us out a total of 11.48 + 5.89= 17.32 years, which is beyond the 15-year study horizon, the model determines that no new investments are required along that specific path during the study horizon. In Column (5), this specific branch shows that, at the end of the study horizon (Terminate at t-15), load will have increased to 1123.7 MW (L =112374). Since that load growth is only 23 MW from the previous node's 1100 MW level, not all of the capacity added by the 345 kV line is used. Therefore, the model "terminates" at the end of year 15 without adding any new capacity. If we go back to Column (3), each of the three Chance nodes shows the 345kV line as the next solution, regardless of load growth rates under the Chance nodes of Column (2). Furthermore, looking at Column (5), which reflects the next set of required decisions, it can be seen that the second Granite Static Capacitor Bank (GR2).

Although the timing of the 345 kV and second static capacitor bank depend on load growth, the model consistently selects those investments to follow the Granite PAR and first static capacitor bank. As a result, these investments constitute a least-expected cost set of investments to provide additional capacity.

Q: Is the $65.03 million dollar cost value reported in Exhibit DPS-JAL-5 the same cost that would be seen in a cost of service filing?

A: No. The AIPM is a planning model in the same context as planning models used by Vermont utilities for integrated resource plan analyses. The AIPM is designed to rank the expected costs of alternative investments, rather than incorporate all of the nuances that enter into cost of service filings.

Q: What capacity investments would be made if the NRP components were not available?

A: The alternative investment path is shown in Exhibit DPS-JAL-6. It begins with installation of 3x50 MW CTs. Following that, under a low load growth path, the next alternative would be to install a 25 MW CT (CT2). If growth is along the second or third branches in Column (2), the next investment would be 25 MW of distributed generation (DG1).

Q: What is the cost of this strategy relative to the NRP strategy shown in Exhibit DPS-JAL-5?

A: The relative cost of this strategy can be determined by comparing the "optimal value" figure in Column (1) of Exhibits DPS-JAL-5 and DPS-JAL-6. The optimal value shown in Exhibit DPS-JAL-5 is $65,030. This means that, over the 15-year time horizon of the study, the lowest expected present value cost path has a cost of $65.03 million dollars. In Exhibit DPS-JAL-6, the optimal value shown in column (1) is $218583.98, or $218.6 million dollars, just over three times greater than the least-cost path with the NRP.

There are several caveats to bear in mind with these figures. First, they are not intended to represent costs that would be incurred when addressing rates. The AIPM is intended to provide relative cost comparisons, not actual rate impacts. Second, these expected cost values include other investments that would be required to meet peak load growth over the entire 15-year planning period, and not simply the cost difference between the NRP and an equivalent amount of capacity. Nevertheless, the 300 percent difference in the relative expected costs of the two investment paths confirms that, from an economic standpoint, the NRP components are least-cost.

Q: What are the results of your analysis using the SRTP as the discount rate?

A: The same analysis performed using an SRTP value of 3 percent shows that the NRP investment path remains optimal on an expected present value basis, as shown in Exhibit DPS-JAL-7. The only difference in this case is that, as a result of the lower discount rate, the expected present value cost increases to $75.923 million.

Q; Did you perform an analysis relaxing the assumption that a 3x50 CT option would be required to maintain reliability?

A: Yes. I performed an analysis assuming that installation of just one CT initially would meet reliability criteria as peak loads increased. The results of this analysis still showed that installation of the Granite PAR + STATCOM1 had a lower societal expected present value cost than the next best alternative – identified as installation of a 25 MW CT (option CT2) – using both VELCO's assumed nominal discount rate and the SRTP.[10] This analysis also continued to show that the 345 kV line would be the next least-expected cost investment with a 95 percent probability.

Q: Did you perform any sensitivity analysis assuming higher summer avoided system energy costs?

A: Yes. I increased the summer system avoided energy cost by 33 percent, to $60/MWh to determine whether either DSM or generation alternatives would be selected instead of the NRP investments. I performed this sensitivity study on the case where I also relaxed the 3x50MW CT requirement, to maximize the flexibility value of generation. This higher system avoided cost increases the value of DSM and generation options, since such investments reduce the need to purchase system energy. The results of this analysis were unchanged: the NRP path still had the lowest expected societal cost, about 28 percent lower than the next best alternative, which began with installation of distributed generation.

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[10] Note that in the initial analyses, installation of a single 25 MW CT (CT2) could only follow installation of the 3x50CT option.

Q: Did you perform an analysis using higher costs for the 345 kV line and higher costs for the Granite STAT2, as discussed in the testimony of DPS witness Mr. George Smith?

A: Yes. Mr. Smith's testimony discussed a cost per mile for the 345 kV line from West Rutland to New Haven of $600,000 per mile, versus a cost of $390,000 per mile assumed by VELCO. This would increase the expected cost of the 345 kV line by $7.5 million. Mr. Smith's testimony also suggests that VELCO underestimated the cost of installing the second static capacitor bank (STAT2). Mr. Smith's testimony indicates that the total cost of installing this second static capacitor bank would be $13 million, rather than the $7.6 million assumed by VELCO.

I re-ran the AIPM with these higher costs. The results, which are shown in Exhibit DPS-JAL-8, indicated that the least-expected cost investment continued to be the Granite PAR and STAT1. Subsequent to that investment, the analysis showed that, if peak loads followed a low growth path, then the next investment (some 11 years later) would be CT2. However, as shown in Exhibit DPS-JAL-8, there is a 95 probability that the next least-expected-cost investment would be the 345 kV line, despite its higher cost. And, if the 345 kV line were installed, the results of the analysis show that it would be followed by the second static capacitor bank at the Granite substation, even under the higher cost assumption for that investment.

I also re-ran the analysis assuming these higher costs, but also with a higher initial avoided energy cost of $60 per MWh, the SRTP as the discount rate., and relaxation of the 3x50MW CT reliability requirement. All four of these factors would tend to favor installation of DSM and local generation options relative to the NRP. Again, however, the results of this analysis indicated no change whatsoever to the optimal investment path, which continued to begin with the Granite PAR + STAT1, and then a 95 probability of installing the 345 kV line, as shown in Exhibit DPS-JAL-9.

Q: Please discuss why your analysis does not agree with the La Capra analysis showing that ARC 5 had a slightly lower societal cost than did the NRP.

A: Because my analysis is probabilistic whereas the La Capra analysis is deterministic, it is difficult to directly compare the two approaches. The La Capra analysis evaluated given resource portfolios, with new capacity resources added on a fixed time schedule. The La Capra analysis was also designed to address peak loads that would reach a given load level. The probabilistic approach I used explicitly accounted for uncertain peak load growth over a longer time horizon. Moreover, my analysis did not impose specific resource portfolios and evaluate them against the NRP, but allowed the model to select an optimally timed resource portfolio.

Q: What do you conclude from all of these separate AIPM analyses you performed?

A: I conclude that the least-expected cost investment begins with the Granite substation PAR and first STATCOM device. Following that, installation of the 345 kV line from West Rutland to New Haven is almost certain to be the next least-expected cost investment, unless peak load growth is much lower than now expected. Finally, I conclude that, if the 345 kV line is developed, the next least-expected cost investment is the second STATCOM device at the Granite substation, even if the costs are higher than VELCO now expects.

4.4. Limitations of AIPM Analysis

Q: Please discuss the limitations of the analysis you performed using the AIPM.

A: The AIPM was designed to be a <u>planning</u> model. As such, it does not account for operational complexities, such as forced outages of generation plants. Nor does the AIPM provide hour-by-hour dispatch of resources. The AIPM also does not evaluate the impacts of different investments on actual system reliability, nor can it determine an "optimal" level of system reliability. Again, the model assumes that investments must be made to maintain a given level of reliability. Finally, the AIPM is limited to the extent that, while it accounts for peak load growth uncertainty, it does not account for uncertainty in fuel costs.

Despite these limitations, the AIPM represents a significant improvement in evaluation of resource alternatives over strictly deterministic approaches, such as the La Capra analysis. By incorporating peak load growth uncertainty and using a dynamic programming solution framework, the AIPM provides more accurate evaluation of resource portfolios than can any deterministic model.

4.5. Other Economic Impacts

Q: What other economic impacts associated with development of the NRP are relevant to determining compliance of the NRP with 30 V.S.A § 248?

A: There are two other economic impacts that should be discussed. First, several intervenors have raised an issue about reduced property values if the NRP were constructed. Reduced property values could adversely affect property tax collections in certain areas and thereby lead to adverse economic impacts if tax rates were increased to compensate for the loss in property values. A second economic impact is the need for reliable power to support the Vermont economy.

Q: Please discuss the property tax reduction issue.

A: It is conceivable that the NRP could result in somewhat lower market values for some properties, especially those that are not currently near any transmission facilities, but would be near such facilities if the NRP were constructed. The magnitude of the reduction in appraised values is unclear, but to the extent that the NRP primarily expands existing facilities, reconductors existing transmission lines, etc., I do not believe this impact would be significant. While there is some published literature on the effects of siting new transmission lines on property tax values, I was unable to find any published studies that evaluated the impacts on property values associated with reconductoring existing lines or running new lines through existing transmission corridors.

Moreover, any evaluation of the effects on property values and property tax collections must compare the NRP against alternatives. Building local generation facilities would have adverse impacts on local property tax values as well, especially if local generation was built near the more populated load centers in Chittenden County. On balance, therefore, I do not believe that the NRP would result in adverse economic impacts associated with reduced property values and lower tax collections when compared with alternative strategies.

Q: Please discuss the need for reliable power to support the Vermont economy.

A: The Vermont economy is highly dependent on reliable power supplies. While I understand that the NRP is not intended to solve the problems that led to the blackout that occurred on August 14, 2003, reliability of the state's electric transmission system is important. Estimates of the total loss to businesses in the United States and Ontario from the August outage, for example, have run into the billions of dollars. The value of lost production at IBM alone, which did lose over 30 MW of load in the blackout, was not insignificant. Closer to home, the last major outage occurred as a result of the ice storm in 1998. Again, there were clearly significant adverse economic impacts from that power outage. Thus, a reliable electric power supply in Vermont is a critical economic factor that must be considered. By improving existing levels of system reliability, the NRP will provide economic benefits to all of Vermont.

5. COMPLIANCE WITH 30 V.S.A. § 248 AND OTHER REQUIREMENTS

Q: Do the components of the NRP identified as increasing peak load capacity in Northwest Vermont meet the requirements of 30 V.S.A. § 248(b)(2)?

A: Yes. My analysis shows that the NRP peak capacity-increasing investments, which Mr. Smith identified as the Granite PAR and STAT1, 345 kV line from West Rutland to New Haven, and Granite STAT2, have a lower expected present value societal cost than any other resource alternatives, even in the absence of PTF consideration. This is true even if one assumes the higher development costs discussed in Mr. Smith's testimony.

Q: Do the components of the NRP identified as increasing peak load capacity in Northwest Vermont meet the requirements of 30 V.S.A. § 248(b)(4)?

A: Yes. The NRP peak capacity-increasing investments will result in an economic benefit to the state and its residents by providing additional peak load capacity at the lowest expected present value societal cost.

Q: Do the components of the NRP identified as increasing peak load capacity in Northwest Vermont meet the requirements of 30 V.S.A. § 248(b)(7)?

A: Yes. The NRP complies with the Draft 2004 Comprehensive Energy and Electric Plan, which was released on December 4, 2004. The investment has the least-expected cost among different generation and DSM alternatives using the probabilistic decision making framework outlined in Chapter 4 of the Draft Plan.

Q: Does completion of the NRP comply the requirement set out in Paragraph 3(a).xv of the Stipulation between VELCO and the DPS in Docket No. 6479?

A: Yes. Paragraph 3.a.xv of this stipulation requires that VELCO[11]

> 3(a) Prior to applying for a CPG for the West Rutland to Williston upgrade, and no later than March 31, 2002, VELCO will provide the Department with the following:
> …
> xv. A least-cost strategy for meeting the stated need taking into account the results of subparagraphs i. through xiv., above;

Based on my analysis, an investment path that begins with the installation of the Granite PAR and STAT1, followed by (with a high probability) the 345 kV line between West Rutland and New Haven, and then followed by STAT2 at the Granite substation, has the lowest expected present value societal cost of any strategy, taking into account alternatives including DSM and local generation, to

[11] Docket No. 6479, Petition of Vermont Electric Power Company, Inc., for a Certificate of Public Good authorizing the construction of certain additions to its high-voltage transmission facilities located in the Towns of West Rutland, Proctor and Cavendish, Vermont, to be known as the Rutland Regional Reliability Project, STIPULATION BETWEEN VERMONT ELECTRIC POWER COMPANY, INC., AND THE VERMONT DEPARTMENT OF PUBLIC SERVICE, May 2001, at 3 (fn. omitted).

improve electric system reliability in northwest Vermont. As such, it complies with the requirements under the Stipulation set out in Docket No. 6479.

Q: Does this conclude your testimony?

A: Yes.